**Table 3-5**

$SO_2$ INCREMENT CONSUMING EMISSIONS FOR **MONTANA** CLASS I AREAS

| Source | BaseYear Emissions | | Current Year Emissions | | Increment Consuming Emissions[1] | |
|---|---|---|---|---|---|---|
| | 24-hr[2] [lb/hr] | annual [TPY] | 24-hr[3] [lb/hr] | annual [TPY] | 24-hour [lb/hr] | annual [TPY] |
| Basin Electric Power Cooperative - Antelope Valley Station | | | | | | |
| Units 1+2 | n/a | n/a | 3,598 | 14,282 | 3,598 | 14,282 |
| Otter Tail - Coyote Station | | | | | | |
| Unit 1 | n/a | n/a | 5,077 | 17,281 | 5,077 | 17,381 |
| Great River Energy - Coal Creek Station | | | | | | |
| Unit 1[4] | n/a | n/a | 4,195 | 14,332 | 4,195 | 14,332 |
| Unit 2[4] | n/a | n/a | 3,552 | 12,817 | 3,552 | 12,817 |
| PPL Corp. - Colstrip (Montana) | | | | | | |
| Unit 3 | n/a | n/a | 672 | 2,945 | 672 | 2,945 |
| Unit 4 | n/a | n/a | 640 | 2,804 | 640 | 2,804 |
| Minnkota Power Cooperative - Milton R.Young Station | | | | | | |
| Unit 1 | 4,208 | 14,176 | 5,575 | 18,788 | 1,367 | 4,612 |
| Unit 2[5] | 4,970 | 18,092 | 6,128 | 21,499 | 1,158 | 3,407 |
| Basin Electric Power Cooperative - Leland Olds Station | | | | | | |
| Unit 1 | 3,469 | 11,869 | 4,931 | 16,833 | 1,462 | 4,964 |
| Unit 2 | 6,575 | 19,999 | 10,179 | 30,947 | 3,604 | 10,948 |
| Montana Dakota Utilities Co. - Heskett Station | | | | | | |
| Unit 1[6] | 590 | 1,734 | 348 | 1,022 | (242) | (712) |
| Unit 2 | 1,628 | 3,895 | 831 | 1,993 | (797) | (1,902) |
| Great River Energy - Stanton Station | | | | | | |
| Unit 1 | 1,989 | 6,178 | 2,456 | 7,629 | 467 | 1,451 |
| Unit 10 | n/a | n/a | 320 | 1,107 | 320 | 1,107 |
| Gas Processing Plants | | | | | | |
| Grasslands | n/a | n/a | 273 | n/a | 273 | n/a |

| Source | BaseYear Emissions | | Current Year Emissions | | Increment Consuming Emissions[1] | |
|---|---|---|---|---|---|---|
| | 24-hr[2] [lb/hr] | annual [TPY] | 24-hr[3] [lb/hr] | annual [TPY] | 24-hour [lb/hr] | annual [TPY] |
| Little Knife | n/a | n/a | 427 | n/a | 427 | n/a |
| Dakota Gasification Plant | | | | | | |
| Greatplain Synfuels | n/a | n/a | 3,323 | n/a | 3,323 | n/a |
| **TOTAL** | **23,429** | **75,943** | **52,525** | **164,277** | **29,096** | **88,435** |

[1] Negative numbers indicate increment expanding emissions (*i.e.*, current year emissions are lower than base year emissions).

[2] Annual numbers are based on the Annual Emission Inventory Reports from 1977-1978 (e.g., *avg* S, annual coal use) and AP-42 emission factors. 24-hr numbers are based on the ratio of the annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

[3] Based on the 90th percentile of the 24-hr average from 1999 and 2000 CEMS data.

[4] Based on 2000 CEMS data only.

[5] Unit 2 had only been operating 9 months in 1977 and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine 1977 emissions. See 45 FR 52718, col. 3, August 7, 1980. 1978 emissions are based on an emission factor of 16.8 S for NSPS boilers (see AP-42, Table 1.7-2).

[6] Current year emissions based on 2000 CEMS data only. Unit 1 does not report to the Acid Rain Database; hourly CEMS data were only available for 2000 from the State.

### 3.4 Increment Expanding Emissions

We modeled six major sources as increment-expanding sources. Montana Dakota Utilities Co's Heskett Station had a reduction in actual emissions since the minor source baseline dates (12/17/77 for North Dakota and 3/26/79 for Montana) and its emissions were therefore modeled as increment expanding. Five other sources in North Dakota shut down after the applicable minor source baseline dates (12/17/77 in North Dakota and 3/26/79 in Montana). These sources include the Amerada Hess Tioga Gas Plant, Basin Electric Power Cooperative's Neal Station (Units 1 and 2), Flying J Inc.'s Williston Refinery, Montana-Dakota Utilities Co.'s Beulah Station (Units 1-2 and 3-5), and the Royal Oak Briquetting Plant (Units 1, 2 and 3).

For the five sources that shut down since the minor source baseline dates, we modeled the same emission rates the NDDH used in their 1999 draft analysis and outlined in Table 3-6.

**Table 3-6**
$SO_2$ INCREMENT EXPANDING EMISSIONS

| Source | Increment Expanding Emissions | |
|---|---|---|
| | ND modeled annual [g/s] | annual [TPY] |
| Basin Electric Power Coop. - Neal Station | 37.4 | 1,301.5 |
| Montana-Dakota Utilities Co. - Beulah Station | 78.2 | 2,721.4 |
| Flying J Inc. - Williston Refinery | 5.7 | 198.4 |
| Amerada Hess Tioga Gas Plant | 62.9 | 2,188.9 |
| Royal Oak Briquetting Plant | 68.9 | 2,397.7 |
| **TOTAL** | **253** | **8,808** |

## 4. Results

The Calpuff modeling results are shown in Tables 4-1 through 4-5. To determine PSD compliance these modeled results are compared with the applicable Class I increments.

The PSD increments for $SO_2$ are specified in section 163(b) of the Act. For Class I areas, those increments are:

annual arithmetic mean...............2 $\mu g/m^3$
twenty-four hour average...........5 $\mu g/m^3$
three hour average....................25 $\mu g/m^3$.

For any averaging period other than an annual averaging period, section 163(a) of the Act allows the increment to be exceeded during one such period per year. Otherwise, section 163 of the Act provides that the increments are not to be exceeded and that the State Implementation Plan must contain measures assuring that the increments will not be exceeded in the future. In the following tables, the number of exceedances indicates the number of times in each year that Calpuff predicted concentrations exceeding the applicable increment. Any number larger than one indicates a violation of the Class I increment.

**Table 4-1. Calpuff Class I Increment Results**
**TRNP-South Unit**
**(μg/m³)**

| | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 3-hr Predictions | | | | | |
| Highest | 36.4 | 31.4 | 25.6 | 35.0 | 29.9 |
| High, 2nd High | 31.4 | 30.0 | < 25 | 25.1 | < 25 |
| Max # of Exceedances | 4 | 2 | 1 | 2 | 0 |
| 24-hr Predictions | | | | | |
| Highest | 14.1 | 15.3 | 6.9 | 8.5 | 10.1 |
| High, 2nd High | 12.8 | 8.5 | 5.4 | 7.3 | 7.7 |
| Max # of Exceedances | 8 | 7 | 2 | 5 | 10 |

**Table 4-2. Calpuff Class I Increment Results**
**TRNP-North Unit**
**(μg/m³)**

| | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 3-hr Predictions | | | | | |
| Highest | 29.4 | 30.7 | 33.8 | 32.3 | 32.0 |
| High, 2nd High | 29.0 | 28.5 | 27.7 | < 25 | 31.4 |
| Max # of Exceedances | 2 | 2 | 3 | 1 | 2 |
| 24-hr Predictions | | | | | |
| Highest | 12.3 | 11.9 | 12.1 | 13.1 | 13.4 |
| High, 2nd High | 10.5 | 9.2 | 7.0 | 7.9 | 9.6 |
| Max # of Exceedances | 9 | 7 | 6 | 8 | 7 |

**Table 4-3. Calpuff Class I Increment Results**
**TRNP- Elkhorn Unit**
**(μg/m³)**

| | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 3-hr Predictions | | | | | |
| Highest | < 25 | < 25 | < 25 | 25.8 | 35.7 |
| High, 2nd High | < 25 | < 25 | < 25 | < 25 | < 25 |
| Max # of Exceedances | 0 | 0 | 0 | 1 | 1 |
| 24-hr Predictions | | | | | |
| Highest | 9.4 | 11.5 | < 5 | 6.5 | 11.9 |
| High, 2nd High | 6.9 | 7.1 | < 5 | 6.4 | 11.4 |
| Max # of Exceedances | 5 | 6 | 0 | 5 | 6 |

**Table 4-4. Calpuff Class I Increment Results**
**Lostwood Wilderness Area**
**(μg/m³)**

| | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 3-hr Predictions | | | | | |
| Highest | < 25 | < 25 | 31.5 | < 25 | 25.6 |
| High, 2nd High | < 25 | < 25 | < 25 | < 25 | < 25 |
| Max # of Exceedances | 0 | 0 | 1 | 0 | 1 |
| 24-hr Predictions | | | | | |
| Highest | 7.6 | 9.1 | 8.9 | 5.9 | 6.4 |
| High, 2nd High | 6.6 | 6.8 | 7.7 | 5.5 | 6.4 |
| Max # of Exceedances | 7 | 10 | 8 | 4 | 7 |

**Table 4-5. Calpuff Class 1 Increment Results**
**Medicine Lakes Wilderness Area**
**($\mu g/m^3$)**

| | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 3-hr Predictions | | | | | |
| Highest | 26.0 | < 25 | < 25 | < 25 | < 25 |
| High, 2nd High | 25.9 | < 25 | < 25 | < 25 | < 25 |
| Max # of Exceedances | 2 | 0 | 0 | 0 | 0 |
| 24-hr Predictions | | | | | |
| Highest | 6.3 | < 5 | 8.0 | 6.4 | 6.1 |
| High, 2nd High | < 5 | < 5 | 5.0 | 5.9 | 5.1 |
| Max # of Exceedances | 1 | 0 | 2 | 2 | 3 |

**Table 4-6 Calpuff Class 1 Increment Results**
**Fort Peck Reservation**
**($\mu g/m^3$)**

| | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 3-hr Predictions | | | | | |
| Highest | 27.9 | < 25 | < 25 | < 25 | < 25 |
| High, 2nd High | < 25 | < 25 | < 25 | < 25 | < 25 |
| Max # of Exceedances | 1 | 0 | 0 | 0 | 0 |
| 24-hr Predictions | | | | | |
| Highest | 7.4 | < 5 | 11.8 | 6.2 | 7.0 |
| High, 2nd High | 6.2 | < 5 | 5.5 | 5.2 | 6.3 |
| Max # of Exceedances | 2 | 0 | 2 | 2 | 3 |

**Table 4-7**
**Calpuff Class I $SO_2$ PSD Increment Results**
**Summary of 5-year Maximum Values (1990-1994)**
**($\mu g/m^3$)**

| | TRNP South | TRNP North | TRNP Elkhorn R. | Lostwood Wilderness | Med. Lake Wilderness | Ft. Peck Reservation |
|---|---|---|---|---|---|---|
| 3-hr Predictions | | | | | | |
| Highest | 36.4 | 32.3 | 35.7 | 31.5 | 26.0 | 27.9 |
| High, 2nd High | 31.4 | 31.4 | < 25 | < 25 | 25.9 | < 25 |
| Max # of Exceedances | 4 | 3 | 1 | 1 | 2 | 1 |
| 24-hr Predictions | | | | | | |
| Highest | 15.3 | 13.4 | 11.9 | 9.1 | 8.0 | 11.8 |
| High, 2nd High | 12.8 | 10.5 | 11.4 | 7.7 | 5.9 | 6.3 |
| Max # of Exceedances | 10 | 9 | 6 | 10 | 3 | 3 |

## 4.1 Results Using Regulatory Default Input Values

EPA conducted a sensitivity test to show the difference in predicted concentrations compared to a regulatory default application of the Calmet and Calpuff models. With the exception of directly monitored North Dakota values (e.g. mixing height, $O_3$/ $NH_3$ background concentrations, etc.), all IWAQM recommendations were selected, and the unrevised EPA regulatory version of the model was used. The results of this test run are shown in Table 4.1-1. From the table it can be seen that the regulatory default selections result in higher predicted concentrations than the selections used in the current study. Non-IWAQM parameters related to the method of dispersion (MDISP, MPDF) were responsible for a large portion of the observed differences. EPA based its selection of non-IWAQM settings largely on the NDDH testing of the model. In these tests Calpuff/Calmet model predictions were compared with observed concentrations for two $SO_2$ monitoring sites located in and near the Theodore Roosevelt National Park located in western North Dakota. The evaluation was limited by the lack of representative monitoring sites so that a full evaluation using American Meteorological Society performance statistics could not be generated, and predictions/observations were not paired in time. Given the relatively sparse set of $SO_2$ monitoring data that has been used in testing the model, EPA solicits public comment on which default values should be used in the final modeling to complete the current study.

**Table 4-8**
**Calpuff PSD Increment Analysis**
**Comparing Modeling Results Using Regulatory Defaults (bold) and Locally Developed Input Settings.**

| **1990 Modeling Results** | **TRNP South** | **TRNP North** | **TRNP Elkhorn R.** | **Lostwood Wilderness** | **Med. Lake Wilderness** | **Ft. Peck Reservation** |
|---|---|---|---|---|---|---|
| 3-hr Predictions | | | | | | |
| Highest | **61.5** /36.4 | **35.1** /29.4 | **27.5** /< 25 | **31.2** /< 25 | **< 25** /26.0 | **25.5** /27.9 |
| High, 2nd High | **45.1** /31.4 | **33.1** /29.0 | **25.8** /< 25 | **< 25** /< 25 | **< 25** /25.9 | **< 25** /**< 25** |
| Max # of Exceedances | **12** /4 | **9** /2 | **2** /0 | **1** /0 | **0** /2 | **1** /1 |
| 24-hr Predictions | | | | | | |
| Highest | **22.4** /14.1 | **15.2** /12.3 | **8.8** /9.4 | **8.4** /7.6 | **< 5** /6.3 | **5.6** /7.4 |
| High, 2nd High | **18.6** /12.8 | **13.8** /10.5 | **8.4** /6.9 | **7.7** /6.6 | **< 5** /<5 | **< 5** /6.2 |
| Max # of Exceedances | **16** /8 | **14** /9 | **6** /5 | **9** /7 | **0** /1 | **1** /2 |

## 5. Conclusion

In summary, EPA has applied the Calmet/Calpuff model to assess increment consumption in four Class I areas in North Dakota and eastern Montana. We based our analysis on long-standing EPA methodologies, including the use of two years of actual emissions data and five years of historical meteorology data. We employed the locally-developed inputs for the model used by the North Dakota Department of Health (NDDH) in their draft 1999 analysis. The results of our analysis show numerous violations of the Class I PSD increments for $SO_2$ in all four Class I areas assessed. Specifically, the number of violations in each Class I area are shown below:

**Table 5-1: Summary of Class I Violations**

| | 3-hr Predictions 2nd High | 3-hr Predictions # Violations | 24-hr Predictions 2nd High | 24-hr Predictions # Violations |
|---|---|---|---|---|
| *Theodore Roosevelt National Park, South Unit* | 31.4 μg/m³ | 3 | 12.8 μg/m³ | 9 |
| *Theodore Roosevelt National Park, North Unit* | 31.4 μg/m³ | 2 | 10.5 μg/m³ | 8 |
| *Theodore Roosevelt National Park, Elkhorn Unit* | <25 μg/m³ | 0 | 11.4 μg/m³ | 5 |
| *Lostwood Wilderness Area* | <25 μg/m³ | 0 | 7.7 μg/m³ | 9 |
| *Medicine Lakes Wilderness Area* | 25.9 μg/m³ | 1 | 5.9 μg/m³ | 2 |
| *Fort Peck Indian Reservation* | <25 μg/m³ | 0 | 6.3 μg/m³ | 2 |
| EPA's Class I SO2 Increments | 25 μg/m³ | | 5 μg/m³ | |

Note that, under EPA's PSD regulations, one exceedance of the short term (3-hour and 24-hour) increments is allowed per year, which is why Table 5-1 identifies the modeled second high concentration.

The PSD permitting program and the State's Implementation Plan, or SIP, are the mechanisms intended by Congress for protecting the PSD increments. Specifically, section 161 of the Clean Air Act and 40 CFR 51.166(a)(1) provide that the SIP must contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality. Section 163(a) of the Clean Air Act states that each SIP shall contain measures assuring that the maximum allowable increases over baseline concentrations shall not be exceeded.

EPA's regulations require States to periodically review their plans for preventing significant deterioration. (See 40 CFR 51.166(a)(4).) If a State determines that an applicable increment is being violated, the State must revise the SIP to correct the violation as required by 40 CFR 51.166(a)(3). In addition, 40 CFR 51.166(a)(2) provides that, if a SIP revision would result in increased air quality deterioration over any baseline concentration, the SIP revision must include a demonstration that it will not cause or contribute to a violation of the applicable increments. Thus, there are several provisions of the Clean Air Act and EPA's regulations which require the protection of the PSD increments.

EPA performed this modeling analysis in order to provide a technical basis for defining the appropriate regulatory actions necessary to address any increment violations. EPA is taking comments from interested parties on this draft report for thirty days. We will consider all comments received before finalizing the results. This draft modeling report does not constitute final agency action; such action may be taken at some point in the future as may be necessary to address any PSD increment violations.

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September 7, 2001

**VIA FACSIMILE
AND U.S. MAIL**

Terry O'Clair, Director
Division of Air Quality
Environmental Health Section
North Dakota Department of Health
1200 Missouri Avenue
Bismarck, ND 58504-5264

RE: Great River Energy
Response to $SO_2$ Increment Information Request

Dear Mr. O'Clair:

Great River Energy has received a sulfur dioxide ($SO_2$) increment information request, addressed to Mr. Jim VanEpps and dated July 3, 2001, from Mr. Jeff Burgess, director of the air quality division for the North Dakota Department of Health (NDDH). In accordance with the schedule agreed to on August 20, 2001 by Mr. Lyle Witham of the North Dakota Attorney General's office and me, the following is Great River Energy's response to the information request. It is our understanding that Mr. Burgess is no longer with the NDDH and so we are submitting our response to you, the current director of the division.

The information request asks for comments regarding the appropriate methodology for calculating baseline emissions, and calculation of historical 3-hour, 24-hour and annual baseline emission rates of $SO_2$ from Great River Energy's North Dakota facilities. Great River Energy (GRE) has two power plants located in North Dakota. These plants are Stanton Station (which consists of Unit 1 and Unit 10), located near Stanton, North Dakota, and Coal Creek Station (which consists of Unit 1 and Unit 2), located near Underwood, North Dakota. GRE does not own or operate any minor emission sources in the state of North Dakota. Stanton Station Unit 1, which was constructed and began operation prior to the major source baseline date of January 6, 1975, is considered a "baseline" emission source. Stanton Station Unit 10 was permitted and began operation after the $SO_2$ major and minor source baseline dates and is not a "baseline" emission source. Based on available information, it appears that Coal Creek Station may not be considered a "baseline" source of $SO_2$ emissions.

As you are aware, GRE does not have certified $SO_2$ continuous emissions monitoring data available for Stanton Station Unit 1 prior to 1995. Accordingly, development of historical emission rates of $SO_2$ may be based on a number of variables including firing capacity, firing rate, fuel quality, applicable emission limits, emission test results, and emission factor characteristics. Much of the information needed to respond to the information request dates back more than 25 years and is not information that GRE is required to keep under any applicable law or permit. GRE has undertaken a diligent effort to locate and identify documents that may assist in responding to this information request. This effort has included identification and review of more than 20 boxes of company records as well as review of the state's files concerning these facilities. While we believe our efforts to respond to the information request have been comprehensive, given the large number of potentially relevant documents, the age of many of these documents, limitations regarding indexing and storage of the documents, and the short time-frame to respond to this information request, we reserve our right to provide the NDDH with additional documents or information that may be identified during our continued review of documents and ongoing efforts to provide the NDDH with all relevant information.

## I. Calculation of Baseline Emissions For Stanton Station Unit 1

With respect to Stanton Station Unit 1, there is no continuous emissions monitoring data and GRE has not identified any performance or engineering test data for the years 1974 through 1977. Thus, there does not exist *any* actual measurement of facility emissions at the $SO_2$ minor source baseline date (December 19, 1977). Accordingly, baseline emissions must be determined on some basis other than actual measured emissions.

### A. "Allowable Emissions" Should be Used to Determine Baseline $SO_2$ Emissions from Stanton Station

The NDDH has requested comment regarding the best information and appropriate methodology for calculating baseline emissions. Further, the NDDH has requested a description of "law, rule, case law, federal guidance or any other information" that supports use of allowable emissions as baseline emission rates. Based on review of applicable law and available information, GRE believes that baseline $SO_2$ emissions for Stanton Station Unit 1 should be based on allowable emissions as of the minor source baseline date (December 19, 1977).

Allowable emissions for Stanton Station Unit 1 should be based on the facility's 1800 million-British-thermal-units-per-hour (mmBtu/hr) heat input rating and the 3 pounds of $SO_2$ per million Btu emission limit under NDAPL § 23-35-06.120 that applied to the facility on December 19, 1977. This limit, which was established considering allowable emissions of existing power plants and specifically considered the allowable emissions from Stanton Station, was established as part of the control strategy for the state and included in North Dakota's initial State Implementation Plan that was approved by the United States Environmental Protection Agency (EPA) on May 31, 1972.

i. North Dakota Law Provides for Use of Allowable Emissions for Establishing Baseline Emissions

The state of North Dakota, based on NDAC 33-15-15-01.1.d.(1)(a), includes in the baseline concentration "actual emissions representative of sources in existence on the applicable minor source baseline date." NDAC 33-15-15-01.1.a(2) defines "actual emissions," "in general," to include those emissions that are "representative of normal source operation." Further, under the definition of "actual emissions," the state has the authority to "presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit." Thus, North Dakota law provides that allowable emissions may be used for determining baseline $SO_2$ emissions.

ii. Allowable Emissions are Representative of Facility Design and "Normal Operation" of the Facility

At the time of the minor source baseline date, Stanton Station Unit 1 had a heat input rating of 1800 mmBtu/hr. This firing capacity was established to accommodate anticipated load. As is the case with most electrical generation facilities, operation fluctuates over time based on demand and other factors. Allowable emissions, which reflect the design and expected operation of the facility, are "representative" of "normal operation" of Stanton Station Unit 1 and should be used to determine baseline emissions for this source. Such an approach is consistent with the intent that increment consumption come from new sources or modifications that occur after the baseline has been set, rather than from the fluctuating production of existing plants.

iii. Use of Two-Year Estimated "Actual" Emissions for Stanton Station is not "Representative of Normal Source Operation" and Results in an Artificially Low Baseline Concentration

Use of a "two-year period" prior to the minor source baseline date, for establishing baseline concentration for Stanton Station, would create an artificially low baseline concentration and would not be representative of "normal source operation," source operation prior to the baseline date, or source capacity at the baseline date. Actual $SO_2$ emissions from the facility are affected by numerous variables, including electrical demand, plant maintenance, and fuel quality. Estimated $SO_2$ emissions are further affected by variables such as emission factor characteristics. Selection of a "two-year period" for estimation of emissions for establishing baseline will artificially reduce baseline such that, even without any modification of the plant, the facility could be viewed as consuming increment based on nothing more than normal emissions fluctuation.

For example, estimated annual $SO_2$ emissions from Stanton Station Unit 1, as calculated by GRE, are as much as 52% different for a given year and have ranged from 5,832 tons/year (1978) to 12,144 tons/year (1990). Further, if 1977 and 1976 were selected as the baseline period, the average annual emissions from that two-year period would be 7,927 tons/year. Estimated actual emissions in 1981 (7,984 tons/year) would then be viewed to consume increment, even though actual emissions from the facility, before the baseline date, in 1974, were more than 1,300 tons greater (9,332 tons/year). Similarly, comparison of hourly emission rates based on estimated emissions could be interpreted to consume increment even though the facility continued to operate normally. Such an approach, however, is counter to congressional intent, and EPA's own statements, regarding how baseline should be calculated for existing facilities. As noted in the legislative history of the Clean Air Act:

> "Baseline pollution level" is the level of pollution calculated to exist assuming plant capacities as of January 1, 1975 . . . . The committee emphasizes that the "baseline pollution level" includes existing sources' emissions calculated on the basis of total plant capacity. For example, even if a plant has been operating at 60 percent capacity, its total capacity for emissions is included in the "baseline . . . . Furthermore, no rollback in emissions from existing plants would be required under the provisions of this section.

H.R. Rep. 95-1175, 95th Cong., 1st Sess. (emphasis added). The House Report repeatedly makes clear that "total plant capacities" are to be included in the baseline concentration:

> The baseline pollution level includes the ambient concentrations calculated to exist, assuming total plant capacities in being on January 1, 1975. . . [and] additional plant capacities for new sources which receive new source permits prior to date of enactment . . . . Therefore, the bill's definition of baseline level authorizes the "grandfathering" of not only all existing industrial capacity, but also of new capacity under construction. . . .

H.R. Rep. 95-1175, 95th Cong., 1st Sess. (emphasis added). Similarly, EPA, in the June 19, 1978 preamble to the New Source Review regulations, stated that:

> Actual emissions also includes into the baseline any future increases in hours of operation or capacity utilization as they occur if such are allowed to the source as of [the major source baseline date] and if the source could have been reasonably expected to make these increases on this date.

43 Fed. Reg. 26388, 26400 (June 19, 1978). In the August 7, 1980 preamble to amendments to the regulation at issue, EPA further refined this policy and provided:

> If a source can demonstrate that its operation after the baseline date is more representative of normal source operation than its operation preceding the baseline date, the definition of actual emissions allows the reviewing authority to use the more representative period to calculate the source's actual emissions contribution to the baseline concentration. EPA thus believes the definition of actual emissions to allow any reasonably anticipated increases or decreases genuinely reflecting normal source operation to be included in the baseline concentration.

45 Fed. Reg. 52676, 52714 (August 7, 1980) (emphasis added). Accordingly, Congress intended, and EPA has reiterated, that increment consumption come from *new* sources

and modifications after the baseline date, rather than from production fluctuations of existing baseline facilities. Use of two-year estimated emissions, however, would result in the contrary. Accordingly, given the lack of any actual emission data from the facility during the baseline period and the existence of an applicable source-derived $SO_2$ limit, baseline is best established for Stanton Station Unit 1 by using allowable emissions from this unit, rather than the two-year estimated "actual" emissions approach.

Use of allowable emissions, based on the facility's 1800 mmBtu/hr heat input rating and the 3 lbs $SO_2$/mmBtu emission limit, as of the minor source baseline date (December 19, 1977), results in the following 3-hour, 24-hour and annual baseline emission rates for Stanton Station Unit 1:

| 3-hour average (lbs/hour) | 24-hour average (lbs/hour) | Annual (tons/year) |
|---|---|---|
| 5,400 | 5,400 | 23,652 |

B. Any Estimate of Baseline "Actual" Emissions For Stanton Station Should Be Based on Best Available Information

Although baseline emissions should be based on allowable emissions, as discussed above, to the extent that any actual emissions estimate is developed for Stanton Station Unit 1, that calculation should be based on best available information. The NDDH provided estimated "actual" $SO_2$ emissions for Stanton Station Unit 1, for the period from 1974 through 1977, with the July 3, 2001 information request. GRE has reviewed these emissions estimates and researched internal and agency records to determine the validity of the NDDH's estimates. Based on this review, GRE believes that the estimate of actual emissions for Stanton Station, for the period of 1974 through 1977, should be higher than initially estimated by the NDDH.

i. The Basis of the NDDH's $SO_2$ Emissions Estimate

The NDDH's estimate of "actual" $SO_2$ emissions is based on information included in the Stanton Station Annual Emission Inventories from 1974 through 1977, and use of the current AP-42 emission factor for lignite combustion. Annual emissions estimates were based on the actual tonnage of lignite burned in the year and the average sulfur content for the year. Maximum hourly emission estimates were based on the maximum firing rate and the maximum sulfur content for the year. Annual tonnage of lignite burned, average annual sulfur content, maximum firing rate, and maximum sulfur content for all calculations were taken from the 1974-1977 Annual Emission Inventories for Stanton Station.

As part of GRE's effort to respond to this information request, the company has worked to identify documents and review the accuracy of the variables identified above. To date, the company has not been able to locate any detailed data regarding annual or short-term firing rates, or sulfur content, or regarding the methodology for assessing such variables, for the years 1974 through 1977. Annual reports submitted to the Rural Electrification Administration (presently the Rural Utilities Service), however, include annual firing rates that are generally consistent with the Annual Emission Inventory reports for the baseline period. Other documents indicate fuel sulfur content that is generally consistent with the range of sulfur content included in the Annual Emission Inventories. Accordingly, at this time, our review of available records suggests the values used by the NDDH from Annual Emission Inventories for firing rates and fuel quality are reasonable for the years 1974 through 1977.

ii. Use of a Facility-Specific Sulfur Multiplier Based on CEM Data Provides a More Accurate Estimate of Past $SO_2$ Emissions

As noted above, the NDDH, in estimating past emissions, used the fuel quality and firing rate data from Annual Emission Inventories in conjunction with an AP-42 emission factor (i.e., $SO_2 = 30S$). The AP-42 emission factor is comprised of two variables; fuel sulfur content, and a sulfur conversion efficiency factor. The sulfur conversion efficiency factor (referred to herein as the "sulfur multiplier") estimates the amount of sulfur in fuel that ultimately will be emitted as $SO_2$. The multiplier used in the NDDH's initial calculations is 30. This factor, as is the case with AP-42 emission factors, is based on an average derived from lignite-fired plants, and does not necessarily represent the actual emissions of a particular facility.

GRE, based on the continuous emission monitoring data from 1995 through 2000, has evaluated the validity of the sulfur multiplier for Stanton Station Unit 1. Based on this facility-specific evaluation, GRE determined a more appropriate facility-specific sulfur multiplier than the generic multiplier included in AP-42.

a. Annual $SO_2$ Emissions Estimate Based on the Facility-Specific Multiplier

Review of Annual Emission Inventories indicates that fuel characteristics pertinent to $SO_2$ emissions generally have been similar throughout the operation of the facility. Attachment A includes a summary of fuel quality data as reported in the Annual Emissions Inventory reports for the years 1974 through 2000. Accordingly, based on five years of available continuous emissions monitoring data, the multiplier that should be used in estimating actual annual emissions for Stanton Station Unit 1 is 33.14. Set forth in Attachment B is a table that summarizes the basis for this annual multiplier. Use of this multiplier results in the following estimated annual $SO_2$ emissions, for Stanton Station Unit 1, for the following years:

| **Year** | **Estimated Annual $SO_2$ Emissions (tons/year)** |
|---|---|
| 1974 | 9,332 |
| 1975 | 8,382 |
| 1976 | 8,037 |
| 1977 | 7,817 |

b. Short-Term $SO_2$ Emissions Estimate Based on the Facility-Specific Multiplier

GRE also has assessed validity of the emission factor multiplier on a short-term basis, again using data from the Stanton Station Unit 1 continuous emissions monitor. Readily available short-term $SO_2$ CEM data from the third quarter of 1998 through the second quarter of 2001 was evaluated. During this period, the maximum 3-hour and 24-hour emission rates occurred on December 22, 1999. Combining the Stanton Station continuous emissions monitoring data with the daily average sulfur content and an estimated firing rate, GRE calculated a short-term emission factor multiplier. The CEM data and other basis for calculation of the short-term multiplier are summarized in Attachment C. Use of the facility specific CEM-based multiplier of 45 results in the following estimated short-term $SO_2$ emission rates, for Stanton Station Unit 1, for the following years:

| **Year** | **Estimated Hourly Emission Rate (lbs/hour)** |
|---|---|
| 1974 | 5,103 |
| 1975 | 5,499 |
| 1976 | 5,711 |
| 1977 | 5,031 |

As indicated in Attachment C, the hourly multiplier is greater than 40. GRE believes this factor of greater than 40, which is theoretically impossible, reflects a flaw in EPA's flow measurement methodology and/or may be attributable to fuel sampling, which may not be representative of the actual hourly sulfur content and heating value of the fuel. Nevertheless, because this multiplier is based on actual hourly data from Stanton Station, rather than the generic average number included in AP-42, GRE believes a multiplier of 45 presents a more accurate assessment of facility emissions. GRE also believes, to the extent that baseline emissions are to be compared to present-day emissions as measured by the $SO_2$ CEM, such an adjustment is necessary to insure a fair "apples to apples" comparison of historic and present-day emission rates.

## II. Increment Expansion and Stanton Station Unit 10

On May 1, 1979, the NDDH issued a construction permit for Stanton Station Unit 10. This permit limits the total $SO_2$ emission rate from Unit 1 and Unit 10 to 4,416 lbs/hour averaged over a 36-hour period. The 36-hour averaging period was changed by the NDDH, on April 25, 1994, to a 24-hour averaging period. Because this emission limit reduces the allowable $SO_2$ emissions from Stanton Station (Unit 1 and Unit 10) below the baseline $SO_2$ emissions for Stanton Station Unit 1, as discussed above, this permit limitation expands available increment.

EPA has long recognized that increment expansion may occur where, following the baseline date, a source limits its emissions through more restrictive permit terms. As noted by EPA in the June 1978 preamble to the New Source Review regulations:

> Reductions in the baseline emissions of sources existing [at the baseline date] generally expand the available PSD increment(s) . . . any renegotiated emission limits more restrictive than those previously permitted will count toward expanding the PSD increment available.

43 Fed. Reg. at 26400-26401. In the August 7, 1980 preamble to the New Source Review regulations, EPA also noted that "emissions reductions after the baseline date increase available increment." See 45 Fed. Reg. at 52720. Similarly, EPA's New Source Review Workshop Manual provides that:

> The amount of available increment may be added to or "expanded" in two ways. The primary way is through the reduction of actual emissions from any source after the minor source baseline date. Any such emissions reduction would increase the amount of available increment to the extent that ambient concentrations would be reduced.

United States Environmental Protection Agency New Source Review Workshop Manual at C.10. Accordingly, the $SO_2$ emission limit in the May 1, 1979 construction permit for Stanton Station Unit 10, expands available increment.

## III. Conclusion

The NDDH's information request asks for comments regarding the appropriate methodology for calculating baseline emissions. In response, Great River Energy has explained why use of allowable emissions for calculation of baseline emissions is appropriate under North Dakota law, necessary to prevent an artificially low baseline concentration, supported by legislative history and EPA preambles, and is most "representative" of "reasonably anticipated" emissions and "normal operation" of GRE's Stanton Station Unit 1.

The information request also asks for calculation of historical 3-hour, 24-hour and annual baseline emission rates of $SO_2$ for any baseline facilities. Great River Energy has provided this information for Stanton Station Unit 1, based on allowable emissions.

Finally, the information request provides an "actual emissions" estimate for Stanton Station Unit 1, based on an AP-42 emission factor, and asks for comments regarding any "more appropriate methodology" for estimating such emissions. In response, Great River Energy has developed a facility-specific sulfur multiplier based on CEM data from Stanton Station Unit 1 and has corrected the NDDH's short term and annual $SO_2$ emissions estimates to reflect the facility's measured sulfur conversion efficiency. Although allowable emissions should be used to establish the baseline concentration of $SO_2$, to the extent that increment consumption is assessed comparing emissions estimates from the minor source baseline date to present-day CEM data, use of the facility-specific sulfur multiplier is necessary to insure a fair comparison.

We trust that the information provided herein satisfies the July 3, 2001 information request. If you have any questions, please call me at (763) 241-2449.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth

Mary Jo Roth, Manager
Environmental Services

Attachments

c: Lyle Witham
Mark Strohfus
Jim Mennell, ELG

## Attachment A - Stanton Station Fuel Quality Data

| Year | % Sulfur | | | Heat Value (Btu/lb) | | |
|---|---|---|---|---|---|---|
| | Min | Avg | Max | Min | Avg | Max |
| 2000 | 0.45% | 0.64% | 1.17% | 6,125 | 6,764 | 7,659 |
| 1999 | 0.45% | 0.68% | 0.95% | 6,211 | 6,703 | 7,200 |
| 1998 | 0.49% | 0.75% | 1.34% | 6,167 | 6,708 | 7,570 |
| 1997 | 0.27% | 0.69% | 1.08% | 5,940 | 6,670 | 7,150 |
| 1996 | 0.46% | 0.66% | 1.04% | 7,630 | 6,850 | 6,300 |
| 1995 | 0.49% | 0.62% | 1.09% | 6,206 | 6,784 | 7,176 |
| 1994 | 0.47% | 0.65% | 1.14% | 6,184 | 6,775 | 7,171 |
| 1993 | 0.45% | 0.63% | 0.89% | 5,789 | 6,715 | 7,116 |
| 1992 | 0.47% | 0.68% | 1.10% | 6,091 | 6,713 | 7,792 |
| 1991 | 0.51% | 0.85% | 1.11% | 6,452 | 6,808 | 7,123 |
| 1990 | 0.66% | 0.94% | 1.46% | 6,264 | 6,877 | 7,267 |
| 1989 | 0.42% | 0.86% | 1.58% | 6,261 | 6,831 | 7,358 |
| 1988 | 0.40% | 0.65% | 1.11% | 6,000 | 6,697 | 7,195 |
| 1987 | 0.12% | 0.65% | 1.09% | 5,700 | 6,697 | 7,174 |
| 1986 | 0.25% | 0.61% | 1.39% | 5,671 | 6,723 | 7,176 |
| 1985 | 0.60% | 0.75% | 0.99% | 6,580 | 6,820 | 7,052 |
| 1984 | 0.60% | 0.69% | 0.85% | 6,668 | 6,829 | 7,113 |
| 1983 | 0.53% | 0.66% | 1.04% | 6,369 | 6,749 | 6,944 |
| 1982 | 0.52% | 0.65% | 0.78% | 6,600 | 6,869 | 7,071 |
| 1981 | 0.48% | 0.59% | 0.68% | 6,510 | 6,883 | 7,190 |
| 1980 | 0.32% | 0.64% | 0.87% | 6,800 | 7,013 | 7,250 |
| 1979 | 0.43% | 0.63% | 0.77% | 6,450 | 6,958 | 7,261 |
| 1978 | 0.39% | 0.61% | 0.90% | 6,690 | 6,975 | 7,410 |
| 1977 | 0.48% | 0.64% | 0.86% | 6,600 | 6,814 | 7,160 |
| 1976 | 0.48% | 0.65% | 0.94% | 6,200 | 6,965 | 7,170 |
| 1975 | 0.59% | 0.74% | 0.94% | 6,450 | 6,923 | 7,190 |
| 1974 | 0.52% | 0.63% | 0.81% | 6,300 | 6,871 | 7,200 |
| Avg | 0.46% | 0.68% | 1.04% | 6,330 | 6,814 | 7,201 |
| Max | 0.66% | 0.94% | 1.58% | 7,630 | 7,013 | 7,792 |
| Min | 0.12% | 0.59% | 0.68% | 5,671 | 6,670 | 6,300 |

**Attachment B - Stanton Station Unit 1 CEM Data and Annual Sulfur Multiplier Derivation**

| Year | Lignite (tons) | Fuel Sulfur Content | | | CEM SO2 (tons) | SO2 (lb/ton) | Mavg (lb/ton) |
|---|---|---|---|---|---|---|---|
| | | Min | Avg | Max | | | |
| 2000 | 692,290 | 0.45% | 0.64% | 1.17% | 7,658 | 22.1 | 34.57 |
| 1999 | 721,800 | 0.45% | 0.68% | 0.95% | 8,521 | 23.6 | 34.72 |
| 1998 | 602,200 | 0.49% | 0.75% | 1.34% | 7,519 | 25.0 | 33.30 |
| 1997 | 669,766 | 0.27% | 0.69% | 1.08% | 7,437 | 22.2 | 32.19 |
| 1996 | 653,910 | 0.46% | 0.66% | 1.04% | 6,254 | 19.1 | 28.98 |
| 1995 | 599,240 | 0.49% | 0.62% | 1.09% | 6,515 | 21.7 | 35.07 |
| Avg | 656,534 | 0.44% | 0.67% | 1.11% | 7,317 | 22.3 | 33.14 |
| Max | 721,800 | 0.49% | 0.75% | 1.34% | 8,521 | 25.0 | 35.07 |
| Min | 599,240 | 0.27% | 0.62% | 0.95% | 6,254 | 19.1 | 28.98 |

Mavg is the annual sulfur multiplier derived using the annual average sulfur content in the fuel.

**Attachment C - Stanton Station Unit 1 CEM Data**
**and Short-Term Sulfur Multiplier Derivation ***

| Date | Time | 1-hr HI (MMBtu/hr) | 1-hr SO2 (lb/hr) | 3-hr SO2 (lb/hr) | 24-hr SO2 (lb/hr) | Est. Firing** (ton/hr) | 1-hr M (lb/ton) |
|---|---|---|---|---|---|---|---|
| 12/22/99 | 0:00 | 1258.58 | 3220.7920 | 3363.8258 | — | 92.39 | 41.01 |
| 12/22/99 | 1:00 | 1330.23 | 3490.0376 | 3467.7258 | — | 97.65 | 42.05 |
| 12/22/99 | 2:00 | 1558.72 | 4085.1484 | 3598.6593 | — | 114.43 | 42.00 |
| 12/22/99 | 3:00 | 1483.92 | 4089.4304 | 3888.2055 | — | 108.94 | 44.16 |
| 12/22/99 | 4:00 | 1294.44 | 3507.0000 | 3893.8596 | — | 95.03 | 43.42 |
| 12/22/99 | 5:00 | 1575.62 | 4171.9736 | 3922.8013 | 3669.9543 | 115.67 | 42.43 |
| 12/22/99 | 6:00 | 1575.44 | 4206.4541 | 3961.8092 | 3695.5545 | 115.65 | 42.79 |
| 12/22/99 | 7:00 | 1563.49 | 4223.4268 | 4200.6182 | 3720.6393 | 114.78 | 43.29 |
| 12/22/99 | 8:00 | 1550.24 | **4356.4755** | **4262.1188** | 3742.1805 | 113.80 | **45.04** |
| 12/22/99 | 9:00 | 1519.56 | 4046.1536 | 4208.6853 | 3759.6933 | 111.55 | 42.67 |
| 12/22/99 | 10:00 | 1570.15 | 4144.2314 | 4182.2868 | 3780.5232 | 115.27 | 42.30 |
| 12/22/99 | 11:00 | 1409.90 | 3757.7483 | 3982.7111 | **3789.5972** | 103.50 | 42.71 |
| 12/22/99 | 12:00 | 1086.46 | 2820.1252 | 3574.0350 | 3744.6406 | 79.76 | 41.60 |
| 12/22/99 | 13:00 | 1061.27 | 2769.0222 | 3115.6319 | 3713.1107 | 77.91 | 41.81 |
| 12/22/99 | 14:00 | 1086.97 | 2886.8545 | 2825.3340 | 3682.5267 | 79.80 | 42.56 |
| 12/22/99 | 15:00 | 1106.72 | 3041.7493 | 2899.2087 | 3660.7951 | 81.25 | 44.05 |
| 12/22/99 | 16:00 | 1314.06 | 3533.4597 | 3154.0212 | 3659.0854 | 96.47 | 43.09 |
| 12/22/99 | 17:00 | 1486.30 | 3766.3379 | 3447.1823 | 3671.0211 | 109.11 | 40.61 |
| 12/22/99 | 18:00 | 1482.71 | 3853.7769 | 3717.8582 | 3665.8064 | 108.85 | 41.65 |
| 12/22/99 | 19:00 | 1490.31 | 3858.6877 | 3826.2675 | 3659.5299 | 109.40 | 41.49 |
| 12/22/99 | 20:00 | 1480.50 | 3723.8889 | 3812.1178 | 3660.4444 | 108.68 | 40.31 |
| 12/22/99 | 21:00 | 1356.71 | 3338.2896 | 3640.2887 | 3656.7395 | 99.60 | 39.43 |
| 12/22/99 | 22:00 | 1257.47 | 2979.6748 | 3347.2844 | 3648.4619 | 92.31 | 37.97 |
| 12/22/99 | 23:00 | 1294.74 | 3178.6633 | 3165.5426 | 3627.0584 | 95.05 | 39.34 |
| | Avg | 1383.10 | 3627.0584 | 3644.0866 | 3695.1243 | 101.53 | 41.99 |
| | Max | 1575.62 | 4356.4755 | 4262.1188 | 3789.5972 | 115.67 | 45.04 |

* This analysis only considers a small sampling of available SO2 data for Stanton Station Unit 1. To the extent that an estimated emissions approach is used for assessing baseline SO2 concentration, Great River Energy reserves the right to evaluate additional data and revise the sulfur multiplier accordingly.

** Calculated based on a daily average sulfur content of 0.[illegible]% and a higher heating value of 6811 Btu/lb.